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RAMARRO Resources Inc

1999 Annual Report



- 10 Ramarro is a very conservatively managed company that exited the year with no bank debt.
- 9 Since the Company became public in 1987, Ramarro has strategically focused on moderate, but sustainable growth.
- 8 Management has a 30% shareholder interest in the Company.
- 7 Forecasts for natural gas indicate rising prices over the next few years.
- 6 Ramarro operates 98% of its properties.
- 5 Finding and development costs are very low at \$3.96/boe.
- 4 Gas contracts have locked in one-third of fiscal 2000 production at more than \$3.10/mcf.
- 3 All of Ramarro's gas reserves have a long lifespan, generally more than 20 years.
- 2 Ramarro is a gas producer with 86% of production from shallow gas properties.
- 1 Following the tumultuous year for oil and gas stocks, Ramarro stock is currently trading at 1.5 times forward cash flow.

Top Ten Reasons To Own Ramarro Shares

CORPORATE HIGHLIGHTS

	1999	1998
Operations		
Natural gas production (mmcf)		
Total	955.6	924.7
Daily average	2.62	2.53
Average natural gas price (\$/mcf)	2.23	1.86
Oil production (bbls)		
Total	15,420	19,382
Daily average	42	53
Average crude oil price (\$/bbl)	17.79	16.16
Total production (boed)	304	306
Natural gas reserves (bcf)	12.15	13.65
Crude oil reserves (mbbls)	140	316
Financial		
Revenue	\$ 2,808,449	\$ 2,512,966
Cash flow from operations	\$ 1,154,408	\$ 914,332
Per share	\$ 0.074	\$ 0.057
Net earnings	\$ 259,251	\$ 17,981
Per share	\$ 0.017	\$ 0.001
Convertible debentures	\$ 330,000	\$ 330,000
Shareholders' equity	\$ 3,958,369	\$ 3,750,368
Common shares outstanding		
At year end	15,462,673	15,763,173
Weighted average	15,600,381	15,965,715
Share Performance (\$)		
High	0.20	0.32
Low	0.12	0.16
Close	0.20	0.20
Volume	1,160,960	1,305,578

PRESIDENT'S MESSAGE

Ramarro Resources Inc. made excellent financial progress during fiscal 1999 and completed transactions which set the stage for improved physical growth in the upcoming year. This performance was achieved in a year when the impact of low oil prices continued to affect the industry. While oil prices have since recovered, many investors have retreated from oil and gas stocks and there continues to be a lack of equity capital to fund activities.

Ramarro was insulated from these negative affects by its high weighting to natural gas, a very conservative level of debt which included no bank debt, and a very stable source of cash flow through long life reserves.

The Company's highlights for the year included:

- **Daily net production of 304 boed, with an 86% weighting to natural gas.**
- **Cash flow increased 26% to \$1,154,408**
- **Gas contracts for 2000 indicate that substantial price increases will translate into significant cash flow growth.**
- **A further production increase to 337 boed after the September 30 year end**
- **Operations were funded by cash flow and Ramarro exited the year with no bank debt.**

Production additions during the year were primarily from drilling at Cessford, Alberta. Development projects continued to focus on Cessford where a Ramarro-operated drilling program of 12 gas wells was completed in the fourth quarter. Increased production rates due to these wells will improve first quarter results in fiscal 2000.

During the year, Ramarro moved to expand its opportunity base through the acquisition of an undeveloped asset. In August the Company traded its non-operated assets in the Oak area of B.C. to the operator and received \$892,000 in cash, plus an undeveloped but proven asset in Ramarro's Cessford core area. The Oak project was a minority interest in an under performing project over which Ramarro had limited control. On the acquired property, Cessford Quatro, Ramarro immediately initiated a 14 well drilling program. As these wells came onstream in November, the impact of the drilling program will begin to be seen in the first quarter of fiscal 2000.

The sale of the Oak property had a negative affect on production and earnings for the last six months of fiscal 1999. The effective date of the sale was April 1, 1999 which translated to an moderate drop in production and earnings before new drilling at Cessford could replace the Oak production. Drilling at Cessford, including the newly acquired property, has more than replaced the production sold.

A new growth area is western Saskatchewan where Ramarro entered into a farm-out agreement subsequent to year end. Through this agreement, Ramarro will earn a 30% interest in a prospect at East Cantuar. One Lower Shaunavon oilwell has been drilled and completed. Two more wells are planned for the near future. This prospect represents an excellent growth opportunity for Ramarro.

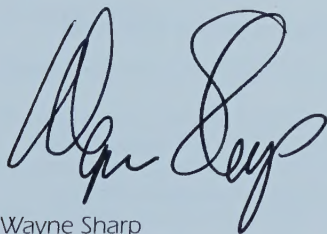
Growth areas for natural gas include Cessford in central Alberta where development projects are expected to add net volumes of 510 mcf/d in fiscal 2000. Ramarro expects increased oil production from the waterflood of the Cantuar oil pool in the Webb, Saskatchewan property in the latter part of the summer of 2000.

As we look to the coming year, Ramarro is well positioned to take advantage of rising energy prices. Based on contracts in place, the Company's average natural gas price will improve substantially during fiscal 2000. Ramarro has entered into fixed price contracts for 33% of its production which will return a net price of \$3.13/mcf. This compares to an average \$2.23/mcf received in fiscal 1999. With this price increase and a stable base of production, Ramarro's cash flow in 2000 will be able to fund an active exploration and development program.

Ramarro believes the current growth in the energy industry and rising commodity prices are a long term trend. Companies in healthy financial condition are assured of increased growth. Oil markets have been very strong and much more enduring than predicted by many experts. Gas markets are bullish and the outlook remains positive as there is increasing utilization of clean burning natural gas in North America. The expanded pipeline capacity to U.S. markets will alleviate the surplus in Alberta's production capacity seen in past years. Ramarro's netback prices will track the North American marketplace. At the time of writing, drilling activity in western Canada is lower than would be expected under the current high commodity price regime. This mitigates against any rapid increase in supply and bodes well for producer returns.

We wish to thank the staff of Ramarro for their dedication and support of the Company and we wish to recognize their valuable contributions to Ramarro's growth.

On behalf of the Board of Directors,

A handwritten signature in black ink, appearing to read 'Wayne Sharp', is positioned above the printed name.

Wayne Sharp
President
January 17, 2000

OPERATIONS REVIEW



Ramarro Resources Inc. has operations based in two western provinces where it participates in 408 producing wells, 98% of which are operated by Ramarro. By acting as operator/manager, Ramarro is able to maximize the economic return from these properties. The Company also generates revenue from operating fees charged to projects which partially cover the cost of maintaining a thoroughly competent and integrated staff.

PRODUCTION

Net daily production remained virtually flat at 304 boed versus 306 boed in fiscal 1998. This reflects the sale of the Oak property in British Columbia effective April 1, 1999 which reduced Ramarro's net production for the final six months of fiscal 1999. Natural gas production increased 3.5% to average 2,618 net mcf/d. An additional 510 net mcf/d was put on production in October and November 1999. In fiscal 2000, Ramarro is projecting a natural gas production exit rate of 3,000 net mcf/d. The average gas price in fiscal 1999 was \$2.23/mcf, up 20% from \$1.86 in 1998.

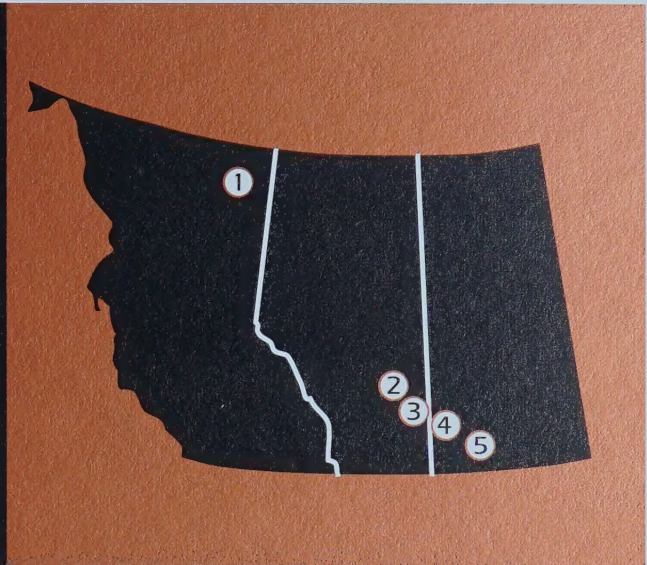
Daily net oil production averaged 42 bopd in fiscal 1999. Ramarro's oil price averaged \$17.79 compared to \$16.16 in fiscal 1998 reflecting the oil price recovery after April 1999. The Company's net oil production is expected to increase to 50 bopd in fiscal 2000.

DRILLING AND ACQUISITIONS

In fiscal 1999, Ramarro participated in 27 wells (10.9 net), all of which were operated by the Company. The overall success rate was 100%.

Principal Properties

- 1 Orion: natural gas discovered in two exploration wells
- 2 Cessford:
 - Cessford East: – fully developed gas property
 - Cessford West – mature gas production
 - Cessford North – most active development area
 - Cessford Quatro – newest gas development
- 3 Hilda: long term fixed price gas contract signed
- 4 Hatton: most prolific gas property
- 5 Webb: project unitized and waterflood installed



GAS PRODUCTION

Hatton

Hatton in southwestern Saskatchewan is a fully developed shallow gas project, however, with low decline rates and long-life reserves, it continues to provide substantial revenues. Current production capacity is 1,140 mcf/d from wells with a life expectancy in excess of 20 years. Ramarro operates 16 of 21 wells in the project at an average working interest of 20%. Production comes from the Milk River, Medicine Hat and Second White Specks zones. The Hatton project covers several townships and is made up of six blocks of land, which were originally freehold lands of the Hudson's Bay Company. Gas sales are under a four-year term gas contract with TransCanada Gas Services (TCGS). This contract returns a price equal to the TCGS "blended netback" which is comprised of 50% Alberta spot prices and 50% NYMEX-related pricing. Proven producing recoverable reserves total 3.67 bcf (net 0.73 bcf).

Cessford East

Ramarro-operated Cessford East is another mature gas property with low decline rates and very long-life reserves. Development was completed in 1998 and total productive capacity is now 1,955 mcf/d. The reserve life exceeds 20 years and proven producing reserves total 8.02 bcf (net 0.75 bcf). The property consists of 71 wells producing from the Milk River or Medicine Hat formations. Gas sales are under a life of reserves contract to PanAlberta Gas and the price floats monthly based on the North American marketplace.

Cessford West

Ramarro operates Cessford West where it holds a 25% working interest in 45 producing shallow gas wells. These wells produce from the Milk River and Medicine Hat zones. Productive capacity totals 1,330 mcf. The property has a long reserve life exceeding 20 years and proven producing reserves total 4.81 bcf (net 1.22 bcf). Gas sales from this property are also under a life of reserves term to PanAlberta.

Cessford North

Cessford North continues to be Ramarro's most active development area. In fiscal 1999, an infill drilling program increased production to 1,660 mcf/d from 1,450 mcf/d in the previous year. Ten wells were drilled in August 1998 and put onstream in October 1998. These wells extended the proven productive area and added to the property's deliverability and reserves. Proven producing reserves of 8.14 bcf (net 3.12 bcf) are projected to be recovered over the 20 year life of the project. In August 1999, 12 more wells were drilled, all productive, that will add to next year's cash flow.

Ramarro operates 62 producing gas wells with interests ranging from 20 - 40%. Texada Energy Ltd. owns the balance of working interests, and Ramarro has a 28.15% share ownership in Texada. Production is taken from the Milk River and Medicine Hat zones.

Ramarro plans to drill 28 more wells over the next three years to complete development of its 4,480 acres (1,792 net) in the area. Seventy per cent of the gas is contracted to TransCanada Gas Services for a four year term and receives the TCGS "blended" price. The balance is being sold under a flat price contract that will yield in excess of \$3.00/mcf for three years.

Cessford Quatro

Cessford Quatro was acquired by Ramarro in August 1999 through an asset exchange that disposed of Ramarro's interest in the Oak property. Ramarro gained a 38.9% interest in the Cessford Quatro shallow gas project which has both production and reserve upside.

Ramarro immediately initiated a 14 well program to fully develop the project. Several tax-motivated partners were brought into the program to partially carry Ramarro's share of development costs and to improve the Company's rate of return. All 14 wells drilled are producing gas from the Milk River and Medicine Hat zones. The drilling program was completed after year end and when the wells came onstream November 1, 1999, production increased to 1,200 mcf/d. Gas from the project is contracted at \$3.45/mcf for the winter 1999 - 2000 and \$3.03/mcf for summer 2000.

Hilda

Ramarro-operated Hilda is comprised of 161 producing Milk River/Medicine Hat gas wells with Company interests ranging from 50 - 67%. The productive capacity of the area totals 2,105 mcf/d. Proven producing reserves total 8.87 bcf (net 5.15 bcf). The project is in the mature stage of development and has demonstrated very low decline rates of less than 4% over in the past four years. Field optimization is underway to improve productivity and lower costs of the project. The Hilda #1 project, which represents about 60% of Ramarro's production from the area, has been contracted for three years at a flat price which will netback in excess of \$3.00/mcf at the plant. With this contract, the project will be very profitable for the next three years. Gas from Hilda #2 is contracted to TransCanada for the balance of the reserve life at a floating price equal to TCGS "blended" price.

OIL PRODUCTION

Webb

Production increases are expected at Webb in fiscal 2000 as the field was unitized effective August 1, 1999. Water injection was initiated on September 16, 1999. The Company operates six producing oil wells which produce medium gravity oil from the Cantuar sand. Current net production is 35 bbls/d. Ramarro's unit working interest is 71.5142%.

Other development activities during fiscal 1999 included drilling a water source well capable of many times the water production that the waterflood scheme requires to repressure the Cantuar zone. This well also has an excellent Cantuar oil zone which will be exploited after the waterflood effectiveness is assessed. Pipelines were installed from the source well to the battery and a well was converted from oil production to water injection.

Based on an analogous offset waterflood project with a 12-year history, Ramarro's share of production from existing wells is projected to double to 55 bopd in two years. Depending on performance of the new waterflood, up to four additional wells may be drilled within two years. Proven recoverable reserves at Webb are estimated at 195,690 bbls (net 139,950 bbls) from existing wells. The waterflood scheme, if successful, will increase the reserves by 197,000 bbls (net 141,000 bbls). These reserves are currently classified as probable by the Company.

EXPLORATION

Orion

The Orion natural gas play in northeastern British Columbia has been inactive over the past year. Two wells have been drilled and tested gas from the Jean Marie zone, which has been the basis for several developments in the area. The two wells established the presence of gas capable of production, however, further drilling of long horizontal wells is required to establish the rates necessary for commercial development. The partners have not indicated a willingness to drill further wells in the upcoming winter drilling season. Ramarro has a 10% interest in this play so that independent operations are not a viable alternative.

East Cantuar

Subsequent to fiscal year end Ramarro farmed into a Lower Shaunavon oil play in western Saskatchewan. This stepout prospect has potential for four medium gravity oil wells. Ramarro operates the project and has a 30% interest in the lands. One well, Ramarro Bolt Cantuar East 12-17-16-16 W3M, has been drilled and cased. This well is currently being evaluated with a current rate of 50 bopd. Ramarro has a 46.15% interest in this well. Two additional development wells are planned for early 2000.

RESERVES AND RELATED VALUE

As of October 1, 1999 Ramarro's in-house evaluation of its proven reserves included 12.15 bcf of natural gas valued at \$7.82 million and 140 mbbls of oil valued at \$0.81 million, both pre-tax using a 15% discount factor.

Proven Producing and Undeveloped Recoverable Oil and Gas Reserves as of October 1, 1999

	Gross Reserves*			Present Worth (\$000's)			Cash Flow (\$000)	
	Oil (mbbls)	Gas (bcf)	Undis- counted	10%	15%	20%	2000	Five Years
Cessford Area	—	6.18	11,072	6,215	5,054	4,266	1,057	4,462
Hatton	—	0.73	589	406	351	310	92	353
Hilda	—	5.15	4,291	2,795	2,379	2,077	602	2,308
Webb	140	—	2,071	1,032	808	663	146	647
Other	—	0.09	37	33	32	30	17	30
Total	140	12.15	18,061	10,481	8,624	7,346	1,915	7,799

*BEFORE ROYALTIES

Pricing assumptions used for this evaluation are summarized in the following table:

	Natural Gas Price (\$/mcf)	Base Oil Price (\$/bbl)
1999 (Q4 only)	3.14	30.00
2000	2.96	27.00
2001	2.94	27.00
2002	2.94	27.00
2003	2.97	27.00
Escalation per year thereafter	3%	3%

Proven Reserves at October 1, 1999

(discounted at 15% pretax) \$ 8,624,000

Undeveloped land 250,000

Balance Sheet Adjustments (as at September 30, 1999)

Working Capital (330,358)

Less: Convertible debentures (330,000)

Net Asset Value Before Investments \$ 8,213,642

Investment in Texada (based on in-house evaluation) 1,201,728

Net Asset Value 9,415,370

Per Share* \$ 0.609

* BASED ON 15,462,673 COMMON SHARES OUTSTANDING AT SEPTEMBER 30, 1999
COMPANY TAX POOLS TOTALLING \$3,095,000.00 HAVE NOT BEEN INCLUDED IN THIS EVALUATION.

MANAGEMENT'S DISCUSSION AND ANALYSIS**Revenue**

Revenue improved 11.8% to \$2,808,449 from \$2,512,966, despite the sale of the Oak property in north eastern British Columbia. Gas sales totaled 955.6 mmcf net of disposition, up 3.5 % from the 924.7 mmcf sold last year. The average gas price improved to \$2.23/mcf from \$1.86/mcf. Crude oil and natural gas liquids totaled 15,420 bbls net of disposition with an average price of \$17.79/bbl compared to 19,382 bbls sold last year at an average price of \$16.16/bbl. Ramarro received \$892,000 cash as well as lands in the Cessford area in exchange for the Oak property, which reduced average production by approximately 30 equivalent barrels of production. The largest gains in revenue net of royalties occurred in our Hilda and Cessford North properties where the Company has entered into a three year gas contract at a price in excess of \$3.00/mcf at the plant gate.

Operating Expenses

Production operating costs were \$869,597 compared with \$825,461 last year, an increase of \$44,136 or 5.3%. Operating costs per boe averaged \$7.84 up from the \$7.38 average in 1998. The balance of the cost difference was due to new wells at Cessford North which were placed on production in the fall of fiscal 1998 and additional working interests acquired during the year.

Administration Expenses

Administration costs were \$665,913, compared to \$691,331 last year down 3.7% or \$25,418. The decrease was mainly due to staff reductions in the 1999 fiscal year. Ramarro does not capitalize any general administrative cost related to exploration and development projects.

Interest and Bank Charges

The year to year change in interest and bank charges to \$100,283 from \$69,580 resulted from increased borrowing through out the year to finance capital projects. The Company has a \$2,000,000 credit facility with a major Canadian Chartered Bank with no balance owing at year end.

Depletion and Depreciation

Depletion and depreciation charges decreased to \$738,682 from \$792,654 in 1998, mainly due to the sale of the Oak property. The allowance for future site restorations was \$60,641, down from the \$67,550 recorded in 1998; again, mainly due to the sale of the Oak property.

Income Taxes

No current taxes were recorded in either of the last two fiscal years as capital write-offs eliminated any taxable income. The increase in deferred income taxes to \$153,673 from \$74,180 reflected the higher income before taxes during the current year. Alberta Royalty Tax credits increased to \$39,591 from \$25,771 because of additional eligible production at Cessford North and the general improvement in natural gas prices.

Share Capital

In January 1999, the Company established a normal course issuer bid on the Alberta Stock Exchange to purchase up to 750,000 shares. Ramarro purchased 300,500 shares under this bid for a total cost of \$51,250 at an average price of \$0.17 per share. These purchased shares represented one of the best investments available to Ramarro in terms of cash flow and boed per share.

Year 2000

The Company conducted a comprehensive review during 1999 of its computer systems to identify the systems that could be affected by the Year 2000 issue. The Year 2000 issue is a result of computer programs being written using two digits rather than four to define the applicable year. Computer programs that have time-sensitive software recognize a date using "00" as the year 1900 rather than the year 2000. There was a concern this this could result in a major system failure or miscalculations. The Company relies on third-party software programs for all of its computer applications. Where programs did not conform to the Y2K problem, new programs were purchased to solve the potential problem. An assessment of the readiness of third parties such as customers, suppliers and other, was also reviewed. However, it was not possible to be certain that all aspects of the Year 2000 issue affecting the Company, including those related to the effects on customers, suppliers or other third parties, would be fully resolved. At the time of writing, Ramarro has passed through the millennium changeover with no apparent problems. The concern appears to have been over estimated throughout the world as no significant problems have yet developed.

MANAGEMENT'S REPORT

The accompanying financial statements of Ramarro Resources Inc. were prepared by management in accordance with accounting principles generally accepted in Canada. Financial information presented throughout the Annual Report is consistent with that shown in the financial statements.

Management is responsible for the integrity of the financial statements. Financial statements generally include estimates that are necessary when transactions affecting the current account period cannot be finalized with certainty until future periods. Based on careful judgments by management, such estimates have been properly reflected in the accompanying financial statements. Systems of internal control are designed and maintained by management to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial purposes.

The external auditors conducted an independent examination of corporate and accounting records in accordance with generally accepted auditing standards to express their opinion on the financial statements. Their examination included a review and evaluation of Ramarro's system of internal control and included such tests and procedures as they considered necessary to provide reasonable assurance that the financial statements are presented fairly.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee of the Board. This Committee meets with management and the external auditors to satisfy itself that management's responsibilities are properly discharged and to review financial statements before they are presented to the Board of Directors for approval.



Wayne Sharp
President
December 14, 1999



B. John Schmidt
Vice President, Finance

AUDITORS' REPORT

To the Shareholders of Ramarro Resources Inc.

We have audited the balance sheets of Ramarro Resources Inc. as at September 30, 1999 and 1998 and the statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at September 30, 1999 and 1998, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

VPMG LLP

Chartered Accountants
Calgary, Canada
December 14, 1999

BALANCE SHEETS

AS AT SEPTEMBER 30,	1999	1998
Assets		
Current		
Cash	\$ 497,577	\$ 76,603
Accounts receivable	1,720,772	878,356
	2,218,349	954,959
Petroleum and Natural Gas Properties (NOTE 2)	5,145,659	5,576,945
Investment (NOTE 3)	532,442	474,604
	\$ 7,896,450	\$ 7,006,508
Liabilities		
Current		
Accounts payable	\$ 2,548,707	\$ 2,078,403
Convertible Debentures (NOTE 5)	330,000	330,000
Provision for Future Site Restoration (NOTE 2)	329,093	271,129
	3,207,800	2,679,532
Deferred Income Taxes	730,281	576,608
Shareholders' Equity		
Common Shares (NOTE 6)	2,061,967	2,101,934
Retained Earnings	1,896,402	1,648,434
	3,958,369	3,750,368
	\$ 7,896,450	\$ 7,006,508
Commitments (NOTE 11)		
Contingency (NOTE 12)		

SEE ACCOMPANYING NOTES TO FINANCIAL STATEMENTS

STATEMENT OF EARNINGS AND RETAINED EARNINGS

YEARS ENDED SEPTEMBER 30,	1999	1998
Revenue	\$ 2,808,449	\$ 2,512,966
Expenses		
Operating	869,597	825,461
Administration	665,913	691,331
Interest	100,283	69,580
Depletion and depreciation	738,682	792,654
Future site restorations	60,641	67,550
	2,435,116	2,446,576
Earnings Before Income Taxes	373,333	66,390
Income Taxes (NOTE 9)		
Deferred	153,673	74,180
Alberta royalty tax credit	(39,591)	(25,771)
	114,082	48,409
Net Earnings	259,251	17,981
Retained Earnings, Beginning of Year	1,648,434	1,658,257
Normal Course Issuer Bid Purchases	(11,283)	(27,804)
Retained Earnings, End of Year	\$ 1,896,402	\$ 1,648,434
Earnings Per Share		
Basic	\$ 0.017	\$ 0.001
Fully diluted	\$ 0.015	\$ 0.001

SEE ACCOMPANYING NOTES TO FINANCIAL STATEMENTS

STATEMENT OF CASH FLOWS

YEARS ENDED SEPTEMBER 30,	1999	1998
Operating Activities		
Net earnings	\$ 259,251	\$ 17,981
Depletion and depreciation	738,682	792,654
Future site restoration	60,641	67,550
Deferred income tax	153,673	74,180
Equity income	(57,838)	(38,033)
Cash flow from operations	1,154,409	914,332
Investment Activities		
Petroleum and natural gas properties	(1,202,073)	(1,358,122)
Proceeds on disposition of properties	892,000	—
Changes in non-cash working capital	(372,112)	418,905
Cash used in investing activities	(682,185)	(939,217)
Financing Activities		
Drawing on credit facility	1,387,000	804,000
Repayment of credit facility	(1,387,000)	(804,000)
Repurchase of common shares	(51,250)	(81,270)
Cash provided by financing activities	(51,250)	(81,270)
Net Change in Cash	420,974	(106,155)
Cash Beginning of Year	76,603	182,758
Cash End of Year	\$ 497,577	\$ 76,603
Cash Flow from Operations		
Basic	\$ 0.074	\$ 0.057
Fully diluted	\$ 0.065	\$ 0.051

SEE ACCOMPANYING NOTES TO FINANCIAL STATEMENTS

Ramarro Resources Inc. ("the Company") is engaged in the acquisition, exploration, development, production and pipeline transportation of oil and gas resources in Western Canada. The financial statements have been prepared in accordance with generally accepted accounting principles in Canada. Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

NOTE 1: ACCOUNTING POLICIES

- a) **Petroleum and Natural Gas Properties:** The Company follows the full cost method of accounting for petroleum and natural gas properties whereby all costs of exploring for and developing petroleum and natural gas properties and related reserves are capitalized. Such costs include land acquisition costs, geological and geophysical expenses and costs of drilling and completion of both productive and non-productive wells. Proceeds from the disposition of properties are normally deducted from the full cost pool without recognition of gain or loss, unless the disposal would alter the rate of depletion and depreciation by more than 20 percent, in which case a gain or loss on disposal is recorded.

Depreciation of lease and well equipment is computed on a straight line basis at a rate of 10 percent per annum. Depletion of the Company's interest in petroleum and natural gas properties is computed by the unit-of-production method based on estimates of proven recoverable reserves. Petroleum and natural gas reserves and production are converted into equivalent units based upon relative energy content.

The Company applies a ceiling test to ensure that the net costs capitalized do not exceed the estimated future net revenues from the production of its proven reserves, plus the cost of undeveloped lands, less impairment. Future net revenues are calculated at year end prices and include an allowance for estimated future general and administrative expenses, interest expense, income taxes, capital expenditures and future site restoration costs. Any costs carried on the balance sheet in excess of the ceiling test limit are charged to income.

- b) **Joint Ventures:** All of the Company's activities are carried on jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.
- c) **Future Site Restoration:** Estimated future site restoration costs are provided for using the unit-of-production method based upon estimated proven reserves. Costs are estimated by the Company based upon current regulations, costs, technology and industry standards. Removal and site restoration expenditures will be charged to the accumulated provision as incurred.
- d) **Investments:** The Company follows the equity method of accounting for its investments in non-controlled corporations, where it does not have significant influences, whereby an investment is initially recorded at cost with the carrying value adjusted thereafter for the Company's pro-rata share of earnings in the non-controlled corporation. Where an investment includes the purchase of flow through shares, the cost of the investment is reduced by the income tax effect of the renounced tax deductions.
- e) **Income Tax:** The Company uses the deferral method of accounting for income taxes. Deferred tax assets and liabilities are calculated using tax rates in effect in the period where differences arise.
- f) **Measurement Uncertainty:** The amounts recorded for depletion and depreciation of capital assets and the provision for future abandonment and site restoration costs are based on estimates. The ceiling test is based on such factors as estimated proven reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.
- g) **Cash:** Cash includes cash on deposit and highly liquid instruments with original maturities of three months or less.

NOTE 2: PETROLEUM AND NATURAL GAS PROPERTIES

The Company's investment in petroleum and natural gas properties is comprised of the following categories and costs:

1999

	Cost	Accumulated Depletion and Depreciation	Net
Petroleum and natural gas properties	\$ 6,930,002	3,010,650	\$ 3,919,352
Lease and well equipment	2,362,591	1,136,284	1,226,307
	\$ 9,292,593	\$ 4,146,934	\$ 5,145,659

1998

	Cost	Accumulated Depletion and Depreciation	Net
Petroleum and natural gas properties	\$ 6,894,383	\$ 2,507,227	\$ 4,387,156
Lease and well equipment	\$ 2,090,814	901,025	1,189,789
	\$ 8,985,197	\$ 3,408,252	\$ 5,576,945

At September 30, 1999, the estimated future site restoration costs to be accrued over the remaining proved reserves were \$474,792 (1998 - \$507,703). Included in cash is \$34,387 (1998 - \$51,107) held on behalf of joint venture partners, for future site restoration costs.

NOTE 3: INVESTMENT

The Company's investment in Texada Energy Ltd., a Canadian controlled private corporation, is summarized in the following table:

	Number of Common Shares	Amount
Balance, September 30, 1997	837,400	\$ 436,571
Equity Income	—	38,033
Balance, September 30, 1998	837,400	\$ 474,604
Equity in income	—	57,838
Balance, September 30, 1999	837,400	\$ 532,442

The Company has invested a total of \$753,400 in flow through shares of Texada Energy Ltd., the cost of which has been reduced by the income tax effect of the renounced tax deductions. At September 30, 1999 the Company held 837,400 common shares representing 28.3 percent of the 2,954,550 common shares outstanding. Equity income for 1998 and 1999 is included in gross revenues.

NOTE 4: BANK LOAN

The Company has arranged a line of credit with a Canadian Chartered bank in the amount of \$2,000,000. Any borrowing will bear interest at the Lender's prime rate plus 0.75 percent and will be secured by an assignment of certain of the Company's natural gas properties, an assignment of book debts and a floating charge debenture. As at September 30, 1999, no amounts were drawn on the facility.

NOTE 5: CONVERTIBLE DEBENTURE

The convertible debentures are unsecured and bear interest at a rate of nine percent and mature on January 31, 2002. Each debenture may be redeemed at par in whole or in part, at the option of the Company after May 31, 1999. Debentures may be converted at the option of the holders, into common shares of the Company at prices varying between \$0.33 and \$0.50 per share until maturity.

NOTES TO FINANCIAL STATEMENTS

NOTE 6: CAPITAL STOCK

Authorized: The Company's capital consists of an unlimited number of Common voting shares and an unlimited number of Class A and B Preferred non-voting shares issuable in series.

	Number of Shares	Common Shares Share Capital
Balance, September 30, 1998	16,165,173	\$ 2,155,400
Repurchase for cash under normal course issuer bid	(402,000)	(53,466)
Balance, September 30, 1998	15,763,173	\$ 2,101,934
Repurchase for cash under normal course issuer bid	(300,500)	(39,967)
Balance, September 30, 1999	15,462,673	\$ 2,061,967

Pursuant to a normal course issuer bid, during 1999 the Company purchased 300,500 (1998 – 402,000) of its issued and outstanding common shares with an average carrying value of \$40,565. The total cost of acquiring these shares of \$51,250 (1998 – \$81,270) exceeded the average carrying value by \$11,283 (1998 – \$27,804), which was charged to retained earnings.

Management has established a plan for granting stock options to the directors, management and employees of the Corporation. At September 30, 1999, options covering 1,300,000 shares at prices ranging from \$0.15 to \$0.22 per share were outstanding which, if not exercised, will expire at various dates during the next five years.

NOTE 7: FINANCIAL INSTRUMENTS

Accounts receivable include amounts receivable for oil and gas sales. These sales are generally made to large, credit worthy purchasers. The Company views the credit risks on these items as low. Amounts receivable from joint venture partners included in accounts receivable are recoverable from production and, accordingly, the Company views the credit risks on these amounts as minimal.

Cash, accounts receivable and accounts payable have carrying values that approximate fair value due to the near-term maturity of these financial instruments. The carrying value of the convertible debentures approximates their fair value.

NOTE 8: RELATED PARTY TRANSACTION

In the year to September 30, 1999, the Company paid \$189,000 (\$240,000 in 1998) under a Management Services and Joint Participation Agreement to a company controlled by officers of the Company.

NOTE 9: INCOME TAX

Income tax expense differs from the amount which would be obtained by applying the basic Canadian federal tax rates to the respective years' income before income taxes. The following table outlines the differences:

	1999	1998
Expected income tax expense at 44.8 percent	\$ 167,253	\$ 29,743
Non deductible Crown royalties net of ARTC	22,682	23,804
Resource allowance	(109,751)	(77,156)
Depletion on assets with no related tax base	34,889	36,739
Equity in non-taxable income of Texada Energy Ltd.	(25,911)	(17,039)
Other items – net	24,920	52,318
Provision for income taxes	\$ 114,082	\$ 48,409

The Company has approximately \$3,095,000 of tax pools remaining to be written off against future years taxable income.

Petroleum and natural gas properties with a net book value of \$512,050 (1998 – \$576,129) has no tax base for income tax purposes.

NOTE 10: YEAR 2000 ISSUE

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000 and, if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failure which could affect an entity's ability to conduct normal business operations. It is not possible to be certain that all aspects of the Year 2000 Issue affecting the Company, including those related to the efforts of customers, suppliers, or other third parties, will be fully resolved.

NOTE 11: COMMITMENTS

The Company entered into an agreement to lease office space for five years expiring July 31, 2003. Lease payments including operating costs and taxes are expected to be \$79,000 per year over the term of the lease.

NOTE 12: CONTINGENCY

The Company is a co-defendant in a legal action concerning sales commissions that would have been paid under a gas sales contract that terminated in May 1995, by mutual consent between the Company and the purchaser. The amount of damages claimed by the plaintiff is material to the Company; however, on the advice of its legal counsel, management believes the claim is without merit and has made no provisions for the amount claimed.

NOTE 13: COMPARATIVE FIGURES

Certain comparative figures have been restated to conform to the current year's presentation.

FIVE YEAR REVIEW

YEARS ENDED SEPTEMBER 30	1999	1998	1997	1996	1995
Financial (ALL AMOUNTS IN \$ EXCEPT OUTSTANDING SHARES)					
Revenue	2,808,449	2,512,966	2,338,131	1,734,389	1,863,660
Expenses					
Operating	869,597	825,461	667,929	558,989	458,155
Administration	665,913	691,331	633,525	578,843	541,241
Interest and bank charges	100,283	69,580	79,529	50,325	45,128
Depletion and depreciation	738,682	792,654	542,945	413,467	401,389
Future site restorations	60,641	67,550	45,496	62,684	47,165
	2,435,116	2,446,576	1,969,424	1,664,308	1,493,078
Earnings before income taxes	373,333	66,390	368,707	70,081	370,582
Income taxes	114,082	48,409	25,898	9,381	141,674
Net earnings	259,251	17,981	42,809	60,700	228,908
Earnings per share					
Basic	0.017	0.001	0.020	0.005	0.019
Fully diluted	0.015	0.001	0.019	0.006	0.017
Cash flow from operations	1,154,408	914,332	959,232	552,806	853,351
Per share	.074	0.057	0.080	0.049	0.073
Shareholders' equity	3,958,369	3,750,368	3,813,657	2,709,646	2,756,019
Shares outstanding					
Preferred	—	—	—	96,978	152,978
Common – at year end	15,462,673	15,763,173	16,165,173	10,976,633	11,255,133
– weighted average	15,600,381	15,965,713	11,913,128	11,095,133	11,278,800
Operations					
Natural gas production (mmcf)					
Total	955.6	924.7	823.9	740.0	738.1
Daily average	2.62	2.53	2.43	2.02	2.02
Average natural gas price (\$/mcf)	2.23	1.86	1.78	1.392	1.210
Oil production (bbls)					
Total	15,420	19,382	10,863	6,889	7,730
Daily average	42	53	30	19	21
Average crude oil price (\$/bbl)	17.79	16.16	21.79	20.56	19.58
Total boed	304	306	290	221	223

CORPORATE INFORMATION

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Calgary, Alberta

G. Donald Meades
Calgary, Alberta

Deane G. H. Ross
Calgary, Alberta

Wayne R. Sharp*
Calgary, Alberta

* Member of Audit Committee

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Solicitors

Burstall Ward
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Bankers

The Bank of Nova Scotia
Calgary, Alberta

Stock Exchange Listing

CDNX: RMA

ABBREVIATIONS

mcf	thousand cubic feet
mmcfd	million cubic feet per day
mcf/d	thousand cubic feet per day
bcf	billion cubic feet
mmcf	million cubic feet
bbl	barrel
boe	barrels of equivalent oil
mbbls	thousand barrels
boe/d	barrels of oil equivalent per day (10 mcf of natural gas to 1 barrel of oil)

CONVERSION FACTOR

Cubic meters of gas to cubic feet x 35.49373

Cubic meters of oil to barrels x 6.29287

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Annual Meeting

The Annual General Meeting of the Shareholders will be held in the McDougall Room at The 400 Club, 710 – 4th Avenue SW, Calgary, Alberta on Tuesday, March 14, 2000 at 4:00 pm (local time).



RAMARRO Resources Inc